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ILLINOIS COMMERCE COMMISSION
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PREPARED SURREBUTTAL TESTIMONY OF
LEONARD M. JONES & MARK J. PETERS
SEPTEMBER 22, 2000

- 1 1. Q. Please state your name, business address and present position.
- 2 A. (Mr. Jones) Leonard M. Jones, Manager of Business Planning and Forecasting,
- 3 Illinois Power Company ("Illinois Power", "IP", or the "Company"), 500 South
- 4 27th Street, Decatur, Illinois, 62521.
- 5 (Mr. Peters) Mr. Mark J. Peters, Control Area Resource Manager, Illinois
- 6 Power Company, 500 South 27th Street, Decatur, Illinois 62521.
- 7 2. Q. Have you previously submitted testimony in this proceeding?
- 8 A. Yes, Direct (IP Exhibits 2.1-2.5) and rebuttal (IP Exhibits 2.6-2.7) testimony.
- 9 3. Q. What additional evidence are you submitting at this time?
- 10 A. We are submitting IP Exhibit 2.8 as our prepared surrebuttal testimony containing
- 11 questions and answers numbered 1 through 13.
- 12 4. Q. Do you have any concerns with statements made by NewEnergy in support of the
- 13 inclusion of imbalance charges in the calculation of MVI?
- 14 A. Yes. The statement made by CILCO Witness Munson, which NewEnergy is
- 15 supporting here, that "imbalance costs are real costs which are not accounted for
- 16 in a published index" is simply misleading. Imbalance, pure and simple is the
- 17 difference between a scheduled load and actual consumption. Imbalance may

18 exist as both a charge when load has been underscheduled and as a credit when
19 load is overscheduled. To the extent that the MVI already accounts for load
20 uncertainty in its pricing, as presented by ComEd witness Huntowski (at page 13
21 of his rebuttal), imbalance is already accounted for.

22 TC's are calculated off of the customer's historical usage and not the
23 schedules which an ARES submits for serving the load. It would be entirely
24 inappropriate to apply an imbalance adjustment based on an individual customer's
25 actual imbalance without simultaneously changing the basis for calculating the
26 TC from the profiled/historical load shape to the schedules which were the basis
27 of the imbalance. To do otherwise would seriously distort the economic basis of
28 the TC calculation and potentially reward those who schedule the worst and
29 through their actions imperil system reliability. An example of this would be an
30 ARES who grossly underschedules a customer's load in every hour of the year by
31 scheduling in a 100% load factor block at the customer's minimum demand.
32 They would indeed incur a substantial cost for imbalance, to account for the fact
33 that they failed to purchase sufficient resources to serve the load they committed
34 to serve – but they never incurred anywhere near the base MVI cost to secure
35 what load they did deliver. Using the MVI example from IP's filed exhibits, the
36 commodity component cost of securing a 100% load factor block would be
37 \$0.03318, whereas a profile 407 (50.2% load factor) customer would have an
38 MVI of \$0.0427.

39 If the imbalance cost associated with the gross underscheduling was
40 allowed to be added to the profile based market value (which reflects load
41 uncertainty and load following through load-weighting and price shaping), rather
42 than to the 100% load factor cost basis suggested by the schedule which created
43 the imbalance, there would be an embedded 9.1 mil error in the MVI.

44 5. Q. Do you have any comment on NewEnergy's continued criticism of the use of the
45 Into Cinergy methodology by Illinois Power?

46 A. Yes. As previously stated, there is no viable Into Illinois Power hub that we are
47 aware of. As such, the use of any other location as the source data will require a
48 basis adjustment. We agree with Staff Witness Zuraski that the Into Cinergy
49 represents an adequate representation of prices for Illinois Power once a basis
50 differential is applied. We believe that the studies presented by Staff Witnesses
51 Zuraski and Christ support the close relationship of prices between Cinergy and
52 Illinois Power and support Mr. Christ's conclusion that our proposed
53 multiplicative adjustment is a better method for handling this basis differential.

54 While NewEnergy has questioned the use of Into Cinergy for use by
55 Illinois Power, we cannot find where they have proffered any alternative other
56 than Into ComEd. We object, however, to being forced to use an index whose
57 depth and veracity are being questioned to a much greater degree by others in this
58 proceeding. It appears that, by challenging the use of basis differentials in
59 general, NewEnergy is suggesting that the only valid index is Into ComEd, and

60 then only for ComEd, thereby leaving the balance of the state without a viable
61 alternative to the NFF. We find this concept to be untenable.

62 6. Q. Is Illinois Power willing to change its hierarchy in regard to the inclusion of
63 bid/offer data for contracts in which actual trades occur?

64 A. Yes, if sufficient evidence exists that such a change is actively supported by Staff,
65 the various ARES and a significant number of customers. The proposed
66 methodology was developed in light of significant debate and concern regarding
67 the inclusion of bid/offer data in the index calculation and was intended to
68 minimize the impact of these unexecuted values. We agree that the methodology
69 as proposed could allow a single transaction to override other bid/offer
70 representations that may have existed, but reiterate that as an executed transaction,
71 it clearly demonstrates a level at which agreement was reached on value, whereas
72 the bid/offer represents a range in which one would expect to see eventual
73 agreement.

74 Given the expressed concerns of many in this proceeding, and the
75 testimony of Staff in regard to the manner in which bids and offers were
76 developed for ComEd's initial, Into ComEd-based MVI, IP understands the
77 concerns of utilizing bid/offer data in the Into ComEd market. Since IP is not
78 willing to modify its proposal to change from an Into Cinergy to an Into ComEd
79 index, we believe, as NewEnergy has suggested (at p. 8 of its rebuttal), that this
80 would be of less concern for our proposal.

81 7. Q. Do you have any comment in regard to NewEnergy's continued assertion (at
82 rebuttal, p. 9) that the MVI as proposed by Illinois Power does not adequately
83 represent the value of the "freed-up firm electric power and energy the utility can
84 sell over the minimum one-month switch period".

85 A. Yes. We find it misleading when NewEnergy, among others, appears to argue
86 that for every megawatt of load which leaves the host utility, the utility has an
87 another megawatt to sell as firm in the open market. This assertion fails to take
88 into account several points:

89 1) Not every MW that leaves is firm. A significant portion of the load currently
90 on Delivery Services is non-firm.

91 2) Unlike an ARES who has the luxury of picking and choosing its customers,
92 Illinois Power is required by statute to accept all customers who choose to
93 take service from them, without regard to notice periods, available supply
94 resources or the demand requirements of the customer. The provider of last
95 resort requirement imposed upon Illinois Power as provider of both imbalance
96 service and what has been termed as no-fault default service, requires that
97 Illinois Power maintain sufficient reserves to meet these potential needs,
98 whenever they may occur. As such, for every MW that takes alternate choice,
99 the Company may not have a full MW available to sell.

100 3) While the MW which is freed up was being used to serve a full requirements
101 customer in every hour in which that customer consumed energy, it is not
102 clear that, when that supply is provided by a third party, there is adequate

103 demand remaining to allow the utility to sell the “freed up power and energy”
104 to another customer – wholesale or retail

105 NewEnergy and others have argued that one must look at the actual
106 product being purchased by retail customers, rather than a suitable representation
107 of the value of power and energy in the region. Using similar logic, the value to
108 Illinois Power of the freed up MW may be substantially different (and likely
109 lower) than the MVI. The statute does not say that only one participant’s value
110 shall set the market. Rather it refers to the mutual market in which both utilities
111 and customers operate. To argue for a multitude of upward adjustments due to
112 supposed additional costs borne by customers, without making similar, offsetting
113 downward adjustments to reflect reduced value for the utility is inappropriate.

114 8. Q. Does IP agree with ComEd witness Huntowski’s testimony in regard to the off-
115 peak component of the MVI?

116 A. Yes. IP agrees that forward prices would be preferable to historical prices in the
117 development of off-peak prices, but that forward off-peak or around-the-clock
118 prices are not readily available. We support the concept that historical off-peak
119 prices are a suitable proxy for these prices given their relative stability over time.

120 We are also pleased to see that Mr. Huntowski has presented a rebuttal to
121 NewEnergy’s contention that the use of historical data tends to bias the MVI
122 downwards, which is similar in many respects to the rebuttal to this issue which
123 IP itself has presented. In particular, IP could not agree more wholeheartedly,
124 with his statement (at p. 12) “If buyers knew that generators were going to dump

125 power at cheap prices, then why would they agree to buy power at very high
126 prices on a forward basis?"

127 9. Q. Mr. Peters, do you specifically, support ComEd witness Naumann's rebuttal of
128 NewEnergy's characterization of "good faith scheduling"?

129 A. Yes. In addition to those current responsibilities identified in my previous
130 testimony, I am also responsible for the forecasting and scheduling of customer's
131 PPO loads as their transmission service agent. It has been my experience in
132 performing these duties, that 1) ComEd's business practices are consistent with
133 what Mr. Naumann has presented, and 2) that Illinois Power's transmission
134 service's business practices are also consistent with those presented for ComEd by
135 Mr. Naumann. It is my understanding that a good faith hourly schedule does not
136 require hourly, real time updates and that block scheduling – particularly an
137 "Aztec pyramid" or "wedding cake" – is permitted. More significantly, I am
138 unaware of any requirement that an ARES supply a customer with only native
139 load firm or load following service across network designated service. ARES are
140 free to obtain point-to-point transmission service both firm and non-firm or
141 network undesignated service in addition to network designated service. While an
142 ARES must demonstrate that it has a real network resource available to it to
143 secure network designated service, it may freely "build a supply portfolio to meet
144 its schedule in any way that it sees fit, including purchases and sales of standard
145 wholesale products," as Mr. Naumann notes at p. 7.

146 While this may present certain risks to the ARES, it also provides an
147 opportunity to secure resources at prices well below that used in the calculation of
148 the MVI – even when combined with whatever designated network resource costs
149 they may have incurred if they chose to obtain network designated transmission
150 service. It is this concept of risk transfer and various risk appetites, which makes
151 for a robust, active market.

152 10. Q. Has NewEnergy misstated Illinois Power's transmission service requirements?

153 A. Yes. NewEnergy is supporting an incorrect assertion made by CILCO witness
154 Munson. Illinois Power does not require a 15% planning reserve margin and
155 therefore there is no basis for the adjustment NewEnergy is supporting.

156 11. Q. Do you have additional reasons to support your conclusion that CILCO is
157 incorrect?

158 A. Yes. Illinois Power's proposal for calculating non-firm MVI values includes a
159 15% reduction from the Firm price. The reason for this is that the firm price
160 already contains a component for short term planning reserves. Although CILCO
161 has yet to change its conclusion, it has in fact recognized the validity of IP's
162 position in response to IP's first set of data requests. CILCO quotes our direct
163 testimony on the Non-Firm adjustment and goes on to state that "IP recognizes the
164 fact that to serve a customer with Firm Energy a RES must secure and pay for an
165 additional 15% to cover for reserves. This is an additional cost to serve customers
166 in IP's territory and should be accounted for by increasing the market value in
167 IP's territory." However, the price of Firm Energy is already reflective of a

reserve/capacity component, which is the basis of our proposal to remove this reserve/capacity component to calculate the value of Non-Firm energy. CILCO is really recommending that this value be counted for twice.

12. Q. Does IP agree with Ameren witness Hock's characterization of IP's proposed method of calculating a separate annual TC for each of the 12 anniversary months?

A. No. While we agree with his statements that a given method is preferred by a given utility and may suit them best for a variety of reasons, we do not concur with the conclusions he has reached in comparing the A/B method with the 12 month method.

First, there is obviously a substantial number of customers in Illinois who have yet to exercise choice. For those desiring a one year contract from a supplier, whether that be through an ARES or the PPO, the only means those customers have under Method A/B of securing a 12 month certain TC on their initial enrollment is to take choice in June. (Certainty here is discussed only in regard to the commodity portion and assumes that the base T&D rates remain unchanged.) For all other customers they must either limit the length of their initial contract or sign a one year contract without certainty of TC's for the latter portion of the contract. Either presents a risk to the customer. A customer electing choice in September who limits its contract length (either by choice or by lack of offers from ARES) faces a risk that there will not be any competitive offers the next summer and will be forced to take service either through the PPO or the utility's

190 bundled service – either of which represents a one year commitment. If the same
191 customer instead enters into a one year contract, it does so without knowing its
192 TC for the last three months of the contract. Under IP’s proposal, the customer
193 receives 12 month certainty of its TC, regardless of the month in which it chooses
194 to enroll.

195 Second, while much has been said by both Ameren and ComEd about the
196 A/B method being calculated closer to the summer, which we agree is the most
197 volatile time period, IP finds this argument to have little significance. It is not the
198 proximity to summer which matters, but rather the proximity of the calculation
199 date to the effective period of the resultant TC which is truly important. IP has
200 consistently argued that when the date of TC calculation is separated from the
201 date at which the TC becomes effective, issues of “free options” and gaming
202 opportunities become significant. IP’s proposal is superior to the A/B method in
203 this regard.

204 IP calculates each and every period’s TC closer to the effective date of the
205 TC than the A/B method would. IP’s average delay from the last date of data
206 capture to effective date is 39 days – every month. The A/B method has an
207 average delay from the last date of data collection to effective date of the TC of
208 116.5 days for the A period and an astounding 207 days for period B. The
209 *shortest* lag for Period A is 71 days, while the *longest* delay under the 12 month
210 methodology for the same period is only 54 days. While we agree that a customer
211 electing choice in September under the IP proposal has a TC based on

212 July/August values which are 11 and 12 months in the future, the risk of the
213 uncertainty falls primarily on those best able to hedge it – the utility and the
214 ARES. Since the July/August component is based off of then current values
215 either party can use the forward financial markets to capture the current price and
216 mitigate the risk of price movement. To say this otherwise - since the effective
217 date of the TC is closer to the calculation date than under the A/B method in *any*
218 month, it is more likely that the parties can buy or sell the underlying contracts as
219 a hedge at the time of customer choice, at the same rates which were used in the
220 calculation.

221 Third, the 12 month method maintains the integrity of the TC calculation
222 for all customers. For those exercising choice under the Period B, they are billed
223 using the stub TC which cannot be calculated within the context of the statute
224 without unduly biasing the TC upwards (we leave for legal briefing whether any
225 stub TC calculation can be performed under the statute). TC's are required to be
226 calculated by using average, annual values for load and base revenue. Virtually
227 all base rates used to calculate TC's in Illinois have a summer rate higher than the
228 non-summer rate. Period B does not include market values for the highest cost,
229 summer months. When an average annual base rate forms the basis of a TC
230 calculation which utilizes a market value component which excludes values for
231 the summer period, TC's are overstated. To avoid overstating TC's, the summer
232 month's values in the base rate must be excluded from the calculation. Our
233 understanding is that these values cannot be excluded from the calculation. As

such, it appears that Period B requires the use of a base rate component which is higher than the customer's actual average rate for the period for which B is calculated – thereby necessarily biasing the TC for a Period B customer upwards. The following is a very simple example of the impact of including the annual average base rate in Period B vs. the Period B only average base rate. It is clear that including the higher summer values in the calculation increases the resulting TC's.

Customer Base Rate

	Kwh's	\$/Kwh	
Jan	100	\$ 0.050	\$ 0.050
Feb	100	\$ 0.050	\$ 0.050
Mar	100	\$ 0.050	\$ 0.050
Apr	100	\$ 0.050	\$ 0.050
May	100	\$ 0.050	\$ 0.050
Jun	100	\$ 0.075	
Jul	100	\$ 0.075	
Aug	100	\$ 0.075	
Sep	100	\$ 0.075	\$ 0.075
Oct	100	\$ 0.050	\$ 0.050
Nov	100	\$ 0.050	\$ 0.050
Dec	100	\$ 0.050	\$ 0.050
Annual Annual		\$ 0.058	
Stub Period B Average			\$ 0.053

TC Calculation

	Annual	Period B
Base Rate	\$ 0.058	\$ 0.053
Market Value	\$ 0.040	\$ 0.040
T&D	\$ 0.008	\$ 0.008
Mitigation	\$ 0.005	\$ 0.005
Transition Charge	\$ 0.005	\$ -

242 While Illinois Power continues to maintain that its 12 month methodology
243 is preferable for the reasons stated above and elsewhere in our testimony, we have
244 not advocated forced uniformity on this issue, nor have we changed our position
245 on this matter.

246 13. Q. Does this concluded your prepared surrebuttal testimony?

247 A. Yes, it does.